

Appendix II:

Ontario's Industry Emissions Reduction Plan:

Abatement Cost Report for Nitrogen Oxides (NO_x) and Sulphur Dioxide (SO₂)

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1 Introduction

In October 2001, Ontario announced its intention to begin consultations on the introduction of nitrogen oxides (NO_x) and sulphur dioxide (SO₂) emission limits for major industry sub-sectors in Ontario (Ontario's Industry Emissions Reduction Plan), and the expansion of its emission trading system to include large industrial emitters. To support these consultations, the Ministry of the Environment retained a contractor to undertake detailed studies for 28 facilities in seven sub-sectors to identify emission control options and abatement costs to major point sources of NO_x and SO₂.

This report summarizes the data and analysis on technology and cost to support the development of emission limits for the Industry Emissions Reduction Plan. This information is intended to help stakeholders understand the costs of control across the different sub-sectors and the different perspectives that can be taken in defining the economic opportunities that exist for emission reductions. This paper builds on the existing data included in the Discussion Paper entitled, "Discussion Paper: Ontario's Clean Air Plan for Industry", released by the Ministry in December 2002 and benefits from the comments received by the Ministry on the costs and technical information provided in that paper.

The information in this paper includes:

1. an analysis of technologies available for NO_x and SO₂ reductions,
2. the costs of reductions and,
3. the uncertainties associated with the costing and economic analysis.

The government uses this information in conjunction with other available data in evaluating reduction opportunities and considerations.

2 Emissions and Control Techniques

2.1 Sources of NO_x Emissions and NO_x Control Techniques

NO_x is formed during the high-temperature combustion of fuel (e.g., natural gas, fuel oil, coal, coke, wood). The primary industrial source of NO_x is combustion in boilers, heaters, furnaces and kilns. In 2000, industrial sources (excluding electricity) accounted for 17 per cent of Ontario's NO_x emissions.

There are many options available for reducing NO_x emissions. Table 1 provides a summary of the most common NO_x control options that are currently available. In the context of a policy timeframe that extends beyond 2010, it is important to note the potential

for the commercialization of new technologies within that timeframe, and for the cost of existing technologies to fall even while their performance improves.

Table 1: Common NO_x Control Techniques¹

Control Technology	Acronym	% Emission Reduction	Remarks
Energy Efficiency/Conservation Measures	EE/EC	Varies	Using less fuel reduces the generation of NO _x . Each facility will have different opportunities for optimizing processes and equipment to reduce fuel consumption. ²
Low excess air	LEA	Up to 15%	Limiting excess air will reduce nitrogen available and hence reduce NO _x formation.
Low-NO _x burners	LNB	10-60%	Low-NO _x burners (LNBs) mix the air and fuel to reduce NO _x formation.
Ultra Low NO _x Burners	ULNB	70-75%	Ultra low-NO _x burners (ULNB) are second generation LNBs that achieve even greater NO _x reductions.
Over-fired air	OFA	Up to 35%	OFA equipment injects air into the different zones of the combustion chamber to reduce NO _x formation.
Low-NO _x burners plus over-fired air	LNB+OFA	Up to 60%	Combined, LNBs and OFA can achieve reductions of up to 60%.
Flue gas re-circulation	FGR	30-60%	Flue gas re-circulation (FGR) involves recycling about 10-25% of cooled exhaust gases back to the burners.
Selective non-catalytic reduction	SNCR	30-75%	SNCR is an "add-on control" that converts oxides of nitrogen (NO _x) back into molecular nitrogen (N ₂) using a reducing agent, typically ammonia or urea.

¹ Many facilities have installed technologies and have reduced NO_x since 1990.

² The Ministry is aware of the potential conflict between energy efficiency and NO_x reductions as more efficient energy conversion typically can involve higher temperature combustion, while NO_x reduction can call for lower combustion temperatures.

Control Technology	Acronym	% Emission Reduction	Remarks
Selective catalytic reduction	SCR	80-95%	SCR is an "add-on control" that converts NO _x to N ₂ and H ₂ O by the reaction of NO _x and ammonia (NH ₃) within a catalyst bed.

2.2 Sources of SO₂ Emissions and SO₂ Control Techniques

The primary industrial sources of sulphur dioxide (SO₂) are non-ferrous metal smelting/refining and the combustion of fuels containing sulphur (e.g., fuel oil, coal, coke) in boilers, heaters, furnaces and kilns. In 2000, industrial sources (excluding electricity) accounted for 66 per cent of Ontario's SO₂ emissions.

Table 2 provides a summary of the most common control options identified for SO₂, which are currently available. As mentioned previously, it is important to note the potential for the commercialization of new technologies, and for costs on existing technologies to decrease within the timeframe contemplated for this policy.

Table 2: Common SO₂ Control Techniques³

Control Technology	Acronym	% Emission Reduction	Remarks
Energy Efficiency/Conservation Measures	EE/EC	Varies	Using less fuel reduces SO ₂ generation. Each facility will have different opportunities for optimizing processes and equipment to reduce fuel consumption.
Fuel Switching	FS	Up to 100%	By switching to a lower sulphur fuel, facilities can reduce SO ₂ emissions. For example switching from heavy fuel oil to natural gas will reduce emissions by close to 100%.
Dry Flue Gas De-sulphurization	Dry FGD	55-95%	Dry Flue Gas De-sulphurization involves scrubbing SO ₂ with a calcium-based compound (i.e., lime) to form CaSO ₃ /CaSO ₄ (gypsum).

³ Many facilities have installed SO₂ control technologies or switched fuels and emissions have been reduced since 1994.

Control Technology	Acronym	% Emission Reduction	Remarks
Wet Flue Gas De-sulphurization	Wet FGD	90-98%	In Wet FGD systems, the flue gas is sprayed with an aqueous slurry consisting of approximately 10% lime or limestone. The wet scrubbers generate large quantities of spent slurry that require disposal.

3 Approach to Estimating Costs

The cost estimates for sub-sector emission reductions are presented in the appendices. The analysis identifies the applicable emission reduction technologies for each sub-sector. It presents data on emission reductions, associated costs and cost effectiveness (i.e., dollar/tonne of pollutant reduced) of various technologies.

The technology and cost data were compiled as follows:

1. Identification of industrial sub-sectors and facilities that annually emitted more than 1000 tonnes of either NO_x or SO₂.
2. Preparation of facility profiles that included identification of principal NO_x/SO₂ sources at each facility, identification of control options and calculation of control costs.⁴
3. Aggregation of facility data into sub-sector summaries.

Costs provided in the sub-sector profiles were determined using a variety of approaches, including engineering models, literature values, vendor estimates, and company data. All costs were scaled to 2001 Canadian dollars. The estimates may be accurate in some cases to within +/- 30 per cent, but in many cases they may only be considered an order of magnitude estimates. The Ministry used the costing data to generate the sub-sector summaries in the appendices to this report. The Ministry recognizes the inherent uncertainties associated with these types of estimates and decision-making based on the data must recognize the uncertainty.

In the engineering costs study, costs included one-time capital costs and, where possible, typical recurring operation and maintenance (O&M) costs over the useful life of the technology. An annualization formula was used to convert one-time capital costs to an equivalent annual cost. The annualization formula assumed a 20-year planning horizon and an interest rate of 5.8 per cent. The annualized capital cost added to the typical O&M

⁴ Control costs are often controversial. Different views on costs and reduction possibilities reflect uncertainties that are typical and unavoidable in these types of studies.

cost for each technology yielded the total annualized cost for each technology combination, which the Ministry used in subsequent analyses.

It is important to note that the cost and technical actions to achieve various reductions are unlikely to totally reflect the actual implementation costs to industry. Costs and limitations vary from site to site; therefore, it is impossible for the government, and difficult for the industry to accurately predict detailed costs at this stage. While the government and its contractor have identified certain techniques to reduce emissions, they do not necessarily represent the most cost-effective way to achieve the reductions. For instance, most of the cost estimates are based on add-on pollution controls. Industry may be able to achieve the same or greater reductions through cleaner fuels or new, cleaner processes/technologies at a much lower cost or even while realizing net savings.

4 Economic Analysis

While engineering cost estimates provide valuable information about the likely costs of achieving a given level of emission reductions at various facilities, there are other factors that government must consider in deciding emission limits for industry sectors or specific facilities. Foremost among these considerations is the degree to which environmental protection is served and overall societal costs (including the costs of pollution) and societal objectives are affected. Policy makers must also consider other factors:

- industry character and structure (competitive vs. monopolistic)
- trends in firm and sub-sector economic indicators (sales, profit, expenses, debt, etc.)
- prospects for growth
- employment trends
- market scope
- competitive pressures
- competitors' regulatory environment
- age of capital stock
- distributional equity

Government can better understand the impacts of these potential costs on the financial health of the various companies by comparing the annualized cost of achieving emission reductions to the expenses of affected firms, and examining the changes in various financial indicators. These analyses are important but they are limited in some respects by data deficiencies. For example, the cost data are organized according to facility, but

audited financial information is only available at the corporate level. This makes it difficult to ascertain the impacts of possible regulations on the financial viability of a specific facility. Furthermore, audited financial data are not always available for all companies, either because they are privately held or because companies' financial results are consolidated with those of a larger corporation.

It is important to remember that the company, rather than the facility, must ultimately provide the funds needed to implement regulatory requirements. Equally, the economics of investments in pollution control at facilities will be shaped by corporate strategies affecting the facility. Assessments of the financial implications using firm level data can still be useful despite the fact that facility level data would reveal the most accurate effects of abatement costs. Corporate resources would be available to cover abatement costs that may not be recorded in facility level income statements.

The benefits of pollution reduction include a reduction in the costs of pollution on human health, estimated by the Ontario Medical Association at more than \$1 billion. The government will balance these factors in developing a sound proposal for Ontario.

5 Conclusions

Based upon the data presented in this report and the policy considerations outlined above, the following conclusions merit attention:

1. Emission control technologies exist and are in use. Emissions in many industry sub-sectors are substantially below 1990 and 1994 levels.
2. Larger emission reductions are possible. Technologies exist which could continue to reduce emissions from the named sub-sectors.
3. The economic analysis of the various sub-sectors reveals large uncertainties in the cost data and the reduction opportunities. The cost data presented in the appendices shows that even the cost data for a relatively well-established technology such as low NO_x burners can have large ranges, and can show significant differences in cost effectiveness from one sub-sector to another. Site-specific factors are important in determining installation and operational costs of future pollution reduction technologies.
4. In developing limits around NO_x and SO₂, the government has only considered add-on controls as the means of achieving the limits. The Ministry recognizes that add-on controls are often not necessarily desirable in terms of cost-effectiveness and impacts on other environmental issues (e.g., greenhouse gases, waste, etc.). In fact, the historical evidence suggests that the costs of emission reductions tend to be overstated at the outset, and in actual practice are lower than estimated. This is because industry will often undertake alternative strategies that are less costly than add-on controls. The challenge for industry is to consider alternative strategies that would achieve the reductions in the most effective way, while minimizing economic impacts, disruptions to scheduling of capital turnover, and transfer of pollution to other media.

5. Under an emission reduction trading (ERT) system, actual costs for compliance may differ from the estimates provided in this report. Using a flexible market-based mechanism such as ERT encourages facilities that can reduce emissions at relatively lower costs to do so, thereby creating either excess allowances or credits. If a regulated facility cannot cost-effectively reduce its on-site emissions to meet its regulatory limit in a given year, it can buy allowances or credits from a facility that can reduce its emissions at a lower cost. To this end, the Ministry will use cost and technical data in this report to evaluate the integration of industrial facilities into Ontario's existing ERT program.

Appendix A: Carbon Black

1 Overview of the Carbon Black Sub-sector in Ontario

The Carbon Black sub-sector is made up of two facilities in Ontario operated by two multi-national companies, Cabot Canada Ltd. located in Sarnia and Columbian Chemicals Canada Ltd. located in Hamilton. These two Ontario facilities represent approximately 10% of North American carbon black production capacity and 85% of Canadian capacity. The Ontario capacity is approximately 200 kt of carbon black/yr. Over 90% of carbon black produced is used in compounding rubber products (e.g., tires). Carbon black is also used as a pigment in inks, paints and plastics. The demand for carbon black in North America has grown, on average, 2% annually over the last decade. Future growth is expected to be between 1.3% and 2% annually.

2 Production Process Description

Carbon black is made from the pyrolysis or thermal cracking of hydrocarbon feedstock. Cracking reactions, which separate the hydrogen from the carbon, take place in the carbon black furnace that operates between 1,200°C and 1,600°C. The exhaust from the carbon black furnace, referred to as "tail gas" is then used as fuel for the boilers and co-generation units at the facilities. Typical yields of carbon black from feedstock range from 60% to 70% by weight.

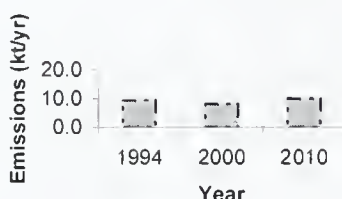
3 Emissions

3.1 Emission Sources

The sulphur in the feedstock oil used in the manufacturing of carbon black is the source of over 99% of the SO₂ emissions from the facility. The feedstock oil used is either coal tar oil or decant oil. Typically, coal tar oil has a sulphur content of less than 1% while decant oil has a typical sulphur content of 1% to 6%. Approximately 30% of the sulphur from the feedstock oil is typically contained in the final carbon black product, while the remaining 70% is emitted as sulphur dioxide in the combusted tail gas.

3.2 Emission Trends

Figure 1: SO₂ Emissions Trends - 1994, 2000 and Projected 2010* Emissions



* 2010 projected SO₂ emissions based on 2% annual growth

The emissions of sulphur dioxide from this sub-sector represent approximately 1.2% of Ontario's emissions. Total emissions of SO₂ decreased 14% from 9.4 to 8.1 kt between 1994 to 2001.

3.3 Estimating Emissions

Emissions are estimated using a mass balance approach. Measuring techniques are used to determine the representative sulphur contents in the feedstock and product. There have been substantial changes in recent emission estimates due to refinements of the estimation methods by the industry.

4 Emission Reduction Technologies

4.1 SO₂ Control Options

There are two cost effective ways to reduce sulphur dioxide emissions from the carbon black sub-sector: reduce the sulphur content in the feedstock oil, or install scrubbers to remove sulphur from the exhaust gas. A third technology, dry flue gas desulphurization, is technically feasible but not currently cost effective. All three technologies are summarized in Table A-1.

4.1.1 Reduced Sulphur Feedstock

Based on a review of 14 new carbon black facilities in the United States that had undergone Best Available Control Technology (BACT) review as part of their approvals process, the only method chosen for SO₂ control was limiting the sulphur content of feedstock. For the U.S. facilities reviewed, the limits on feedstock sulphur content ranged from 2.5% to 4.0% (average 3.4%). The feedstock sulphur content limits at the two Ontario facilities are both within the U.S. BACT range. While low sulphur feedstock is the preferred approach for SO₂ reduction, there are potential issues concerning the local availability of lower sulphur feedstock for Ontario's carbon black sub-sector.

4.1.2 Gas Scrubbers

Scrubbers are an emissions control option for the tail gas from carbon black furnaces and for the combusted tail gas (i.e., boiler or co-generation exhausts). Scrubbing of the tail gas from the furnace is in use at one facility worldwide: a facility in Baytown, Texas.ⁱ Emission testing on this scrubber showed an average removal efficiency of 38% for sulphur containing compounds. Capital and operating costs were not available for this facility.

Scrubbing of the combusted tail gas using dry flue gas desulphurization is a possible technology. Scrubbing of the combusted tail gas was evaluated by the International Carbon Black Association (ICBA) in a 1999 report entitled, "BACT for the Carbon Black Industry". The ICBA estimated the costs of treating the flue gas would be 0.069 US\$/lb carbon black which represented an increase of more than 20% over the nominal selling price of 0.32 US\$/lb carbon black.

Table A-1: SO₂ Control Technologies for the Carbon Black Sub-sector

Technology	Emission Reduction	Remarks
Reduced Sulphur Feedstock	Varies	Reduction varies depending on initial sulphur feedstock content
Scrubber – Tail Gas	38%	Used at one facility world wide, 95% reduction theoretically possible.
Dry Flue Gas Desulphurization – Combusted Tail Gas	80-90%	Technically feasible, but high cost option

5 Emission Limits in other Jurisdictions

5.1 Emissions Limits for SO₂

In the U.S. there are no federal or state limits for SO₂ emissions for carbon black sub-sector. Some facilities have site-specific limits for SO₂ based on the permitting process. As stated previously, for the U.S. facilities reviewed, the chosen method for SO₂ control was limiting the sulphur content of the feedstock. The limits on sulphur content ranged from 2.5% to 4.0% (average 3.4%).

The European Union (EU) is developing a European Best Available Techniques document for the production of carbon black. Current sulphur contents reported for 20 carbon black producing facilities in Europe range from 0.6%-3%, with an average in the 1.5%-2.0% range.ⁱⁱ During the consultation in Europe, the International Carbon Black Association stated: "the establishment of 1.5% annual average S content in carbon black feedstock,

adjusted to local conditions as appropriate, represents an aggressive but achievable benchmark for reducing emissions".ⁱⁱⁱ

6 Costs for Emission Reductions

The cost of achieving a 50% reduction in SO₂ emission intensity (kg/tonne carbon black) from this sub-sector using reduced sulphur feedstock was calculated to be between \$10 and 45 million annually. A cost of ten million dollars per year was calculated based on the 2001 average price of lower sulphur feedstock as reported by the Carbon Black Monitor and the projected production rate for the sub-sector. The sub-sector jointly provided a total cost of \$35-\$45 million annually for a 50% reduction in SO₂ intensity. Their cost estimate was based on higher cost raw material, increased transportation costs, and an allocation for lower yield due to lower sulphur content.

Estimates for Dry Flue Gas Desulphurization costing were provided by Cabot and Columbian based on BACT analysis completed for permits at their U.S. facilities. The values provided for the analysis were converted to Canadian dollars and scaled to the production rates at the two Ontario facilities. Table A-2 summarizes the costs and emission reductions for the SO₂ reduction technologies identified.

Table A-2: Emission Reductions and Costs of SO₂ Control Technologies for the Carbon Black Sub-sector

Technology	Reduction from 2001 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs	Cost Effectiveness (\$/tonne of SO ₂ removed)
	(%)	(kt)				
Reduced Sulphur Feedstock (from 3.0% to 1.5%)	50	4.2	0	10-45	10-45	\$2400-\$10,700
Dry Flue Gas Desulphurization – Combusted Tail Gas	80-90	6.5-7.3	80	52	59	\$8,100-\$9,100

Appendix B: Cement

1 Overview of the Cement Sub-sector

The cement manufacturing sub-sector is made up of seven facilities in Ontario operated by five companies. The cement kilns are the main sources of NO_x and SO₂ emissions from these facilities. There is a wide range of kiln types, ranging from older wet process kilns to long dry kilns with moderate pre-heater capability to state-of-the-art preheater-precalfiner kilns. There is also a wide range in kiln production capacity ranging from 400 tonnes/day/kiln to 5800 tonnes/day/kiln. Raw materials, fuel mixes, and product mixes are additional variables that affect both environmental performance and emissions. The companies, facilities, kiln types, primary fuels used and annual production capacity of clinker are listed in Table B-1.

Table B-1: Ontario's Cement Production Facilities^{iv}

Company/Location	Type of Kiln	Primary Fuel	Annual Clinker Capacity (kilotonnes)
ESSROC Canada (Picton, ON)	Long Dry	Coal, Coke	285
	Preheater		844
Federal White Cement (Woodstock, ON)	Long Dry	Coke, Oil, Natural Gas	190
	Preheater		630
Lafarge (Bath, ON)	Preheater	Coal	1,072
Lafarge (Woodstock, ON)	Wet	Coal, Coke, Natural Gas	265
	Wet		284
St. Marys Cement (Bowmanville, ON)	Precalciner	Coal	1,844
St. Marys Cement (St. Marys, ON)	Preheater	Coke	738
St. Lawrence Cement (Mississauga, ON)	Precalciner	Coal, Coke	1,321
Total			7,473

2 *Production Process Description*

Cement is made from minerals containing calcium, silicon, aluminum and iron. Limestone, marl and chalk are the major sources of calcium while clay, sand, shale, bauxite and iron ore provide the silicon, aluminum and iron components. One of the most common combinations of raw materials is limestone, clay and sand.

Two different processes, namely the "dry" and "wet" process, are used in the manufacture of cement. In the wet process the raw materials, after being crushed and properly proportioned, are ground and thoroughly mixed with water and fed into the kiln in the form of a slurry. In the dry process raw materials are ground, mixed and fed to the kiln in a dry state. The raw material or raw meal is heated to about 1,500°C in cylindrical steel rotary kilns lined with firebrick. Kilns are inclined slightly with the raw material or slurry fed into the higher end. At the lower end powdered coal/coke, oil, gas or other fuels are combusted. The intense heat of combustion in the kiln calcines the raw meal (i.e., drives off the CO₂) and produces cement clinker. The clinker is then mixed with gypsum, limestone and supplementary cementitious material and enters a ball mill to be pulverized into cement.

The dry process is more energy efficient than the wet process due to the increased amounts of energy required to evaporate the water in kilns utilizing the wet process. Within the dry process, cement can be produced by long dry kilns as well as more advanced kilns with preheaters and/or precalciners. Kilns that utilize preheaters are more energy efficient than long dry kilns without preheaters due to the recovery of the waste heat from gases leaving the kiln. In a preheater, the raw meal usually passes through several chambers and is progressively heated before being released into the kiln. Precalciners allow the meal to be 90% calcined before entering the kiln and is the most energy efficient clinker production technology in use today. A total of four wet kilns at Ontario facilities have been mothballed after two facilities installed precalciners in the 1990's.

It should be noted that all facilities add supplementary cementitious materials such as ground steelmaking slag to the clinker produced by the kiln, resulting in increased production of cement with little or no additional NO_x emissions. There is significant variability between facilities in the percent of supplementary cementitious material added. In 2000, Ontario cement facilities averaged 13% supplementary cementitious materials in their product. By 2010, the sub-sector anticipates this average will increase to 16%.

In addition to affecting energy efficiency, the technology used to produce clinker (i.e., wet, dry, preheater, precalciner or preheater/precalciner) also has a substantial influence on emissions. This partially accounts for the wide range in emission intensities from Ontario facilities shown in Table B-2.

Table B-2: Cement Sub-sector Emission Intensity Range for 2000

	kg/tonne clinker	kg/tonne cementitious product
NO _x Intensity	1.9 – 8.1	1.6 – 6.3
SO ₂ Intensity	0.9 – 13.2	0.8 – 10.2

It is recognized that Federal White Cement has a substantially different product than the other facilities. Minimal supplementary cementitious material can be added to white cement without the product becoming too dark. In addition, the fuel consumption per tonne of white cement is typically twice as much as for grey cement. This is due to there being less flux (no iron oxide, no slags, no fly ash) in the white cement production process and because there is no heat recovery in the clinker cooling (due to water quenching of white clinker).

3 Emissions

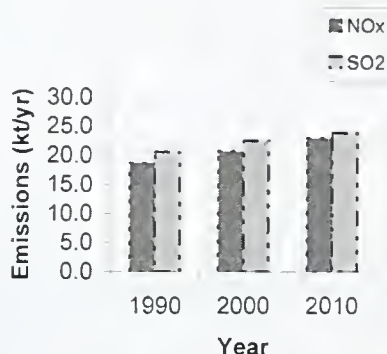
3.1 Emission Sources

Practically all NO_x emissions associated with cement manufacturing are generated in the cement kiln. Favourable conditions for the formation of NO_x are consistently present in cement kilns as a result of the high temperatures and oxidizing environment necessary for the production of clinker.

Practically all SO₂ emissions associated with cement manufacturing are also generated in the cement kiln. Most sulphur (70-95%) contained in materials entering the cement kiln is not emitted as a gas, but instead is usually scrubbed out during the clinker production process (due to the abundant levels of lime and limestone used in the cement production process). Among the primary factors contributing towards SO₂ emissions are the content of reduced sulphur species in the kiln feed (i.e., sulphides such as pyrite and organic sulphur result in increased SO₂ emissions) and low scrubbing efficiency of certain kiln systems. In addition, reducing (i.e., lack of oxygen) conditions within the kiln or lack of intimate contact between exhaust gases and the kiln feed also contributes to SO₂ emissions. Oxidation of sulphides to SO₂ in some instances occurs at temperatures too low for adequate scrubbing by the limestone.

3.2 Emission Trends

Figure 2: NO_x and SO₂ Emissions Trends - 1990, 2000 and Projected 2010 Emissions



The emissions of nitrogen oxides from this sub-sector represented approximately 4% of Ontario's emissions in 2000. Total emissions of NO_x from 1990 to 2000 increased 11% from 18.7 to 20.7 kt.

The emissions of sulphur dioxide from this sub-sector represented approximately 4% of Ontario's emissions in 2000. Total emissions of SO₂ from 1990 to 2000 increased 9% from 20.6 to 22.5 kt.

Over this period clinker production increased by 26%. To meet Ontario's growing housing and construction demand, the sub-sector is anticipating a 21% clinker production increase from 2000 to 2010.

3.3 Estimating Emissions

Emissions are estimated using a variety of techniques. Currently four out of ten kiln exhausts are equipped with continuous emission monitors (CEM's), three that monitor both NO_x and SO₂ and one that monitors only SO₂. The Cement Association of Canada, Ontario section, representing all cement companies in the sub-sector in Ontario, is a signatory to Ontario's Anti-Smog Accord and under the Accord has committed to installing CEM's for NO_x.

4 Emission Reduction Technologies

4.1 NO_x Control Options

Emission controls commonly applied in cement kilns to reduce NO_x emissions include low NO_x burners, staged combustion of air and selective non-catalytic reduction (mostly in Europe).

Each NO_x emission control technology falls into one of three categories, specifically:^v

- process modifications to improve fuel efficiency and kiln operational stability;
- combustion control modifications which minimize NO_x formation; and
- post-combustion control approaches that remove NO_x from the exhaust gas stream.

Table B-3 provides a summary of the NO_x control techniques unique to this sub-sector. Generally applicable technologies, such as low NO_x burners, are not shown here, but are used in the cost analysis that follows.

Table B-3: NO_x Control Techniques Applicable to Cement Kilns

Technology	Applicable To	Emission Reduction	Remarks
Process Modifications			
Process Controls	All Kilns	0-20%	In place at 4 kilns, planned for installation at all gray cement facilities by 2010.
CemStar Process (i.e., use steel slag)	All Kilns	9-40%	Most applicable to wet and long dry kilns.
Optimization of Clinker Burning Process	All Kilns	0-20%	Each facility will have different opportunities for optimizing processes and equipment to reduce NO _x emissions.
Combustion Modification			
Staged Combustion Air (SCA)	Preheater and Precalciner Kilns	10-50%	Not applicable for preheaters firing fuel in the riser.
Low-NO _x Precalciners	Preheaters and Precalciners	30-40%	Planned for two kilns by 2010; partial implementation planned for two more kilns.
Post-Combustion Controls			
Biosolids Injection	Precalciner	30-50%	Used at one cement facility in the U.S.

4.2 SO₂ Control Options

Within the cement sub-sector, SO₂ emission reduction technologies can be allocated into one of two categories, namely: process modifications and add-on control technologies.

Unlike most sources, the nature of the production process actually removes a substantial amount of SO₂ that is generated elsewhere in the process. Various alterations to the production process can further minimize the quantity of SO₂ generated while add-on control technologies capture SO₂ after it has been generated in the process. Among the add-on control technologies that have been employed for SO₂ reduction, the addition of an absorbent into the kiln feed appears to be among the most widespread. The applicability of several emission control techniques is described in Table B-4.

Table B-4: SO₂ Control Techniques Applicable to Cement Kilns

Technology	Applicable To	Emission Reduction	Remarks
Process Modifications			
Optimization of Clinker Burning Process	All Kilns	0-50%	Most applicable to long kilns. Marginal for short kilns.
Post-Combustion Controls			
Absorbent addition (e.g., slaked lime) to Kiln Feed	All Kilns	10-80%	Mostly used in suspension preheaters. Used at 14 cement facilities in Europe. One Ontario facility has installed an absorbent addition system. ^a
Dry scrubber	Dry Kilns	Up to 90%	Used at one cement facility in North America and one cement facility in Europe. Proposed at several new cement facilities in the U.S.
Wet scrubber (Wet Flue Gas Desulphurization)	All Kilns	>90%	Six kilns use wet scrubbers in North America. Five wet scrubbers are used at cement facilities in Europe.

^a however, it is only used during conditions conducive to the formation of a secondary plume

It should be noted that while switching to low sulphur fuels is an option in other sub-sectors to reduce SO₂ emissions, it is not considered a viable option in the cement sub-sector. This

is attributed to the fact that SO₂ emissions from cement facilities have been demonstrated to be almost independent of fuel sulphur.

5 Emission Limits in Other Jurisdictions

5.1 Emission Limits for NO_x

In 1998, the Canadian Council of the Ministers of the Environment (CCME) published a national emission guideline for cement kilns.^{vi} The guideline applies to kilns that are constructed after January 1, 1998 or kilns that are modified so that their capacity is increased by more than 25%. The emission limits for NO_x are summarized in Table B-5. The guideline does not include limits for SO₂.

Table B-5: CCME Guideline Emission Limits for New Cement Kilns

Kiln Type	Fuel	Capacity	Limit (kg NO _x /tonne of Clinker)		
		(tonnes clinker/day)	Daily Average	Monthly Average	Annual Average
Preheater/Precalciner	All	>1,500	2.5	2.3	2.1
Long Dry Kiln	Natural Gas	<1,500	5.7	-	5.0
Long Dry Kiln	Coke/Coal	<1,500	4.0	-	3.0

A review of the United States regulations for NO_x in the Great Lake States identified three main regulatory measures. The first was the Federal Implementation Plan (FIP) which was developed by the U.S. EPA as part of the NO_x SIP Call related to cement kilns. The second was the implementation of a reasonably available control technology (RACT) program. The third is the New York State requirement for cement kilns to participate in the NO_x Cap and Trade program.

Under the FIP cement facilities are required to do one of the following:

- Install low NO_x burners; or
- Implement Mid-Kiln Firing; or
- Implement other measures to reduce emission intensity from 1995 levels by 30%.

Some of the states implementing the FIP are adding a provision that kilns achieving the following annual emission limits are not required to take any further actions to reduce emissions:

- Long wet kiln – 3.0 kg NO_x/tonne clinker

- Long dry kiln – 2.55 kg NO_x/tonne clinker
- Preheater kiln – 1.9 kg NO_x/tonne clinker
- Preheater/Precalciner kiln – 1.4 kg NO_x/tonne clinker

Michigan added an additional provision to the FIP so that implementing RACT was another alternative. Pennsylvania has required the installation of RACT on all its existing cement kilns and is now proposing to add the FIP to its regulatory requirements. The FIP is a regulatory requirement in New York State with emission trading also being required.

In Europe, the emission limits for NO_x have been applied in most EU countries to the cement sub-sector. In Germany, limits have been set for both new and existing facilities. As a result, in 2001 of the 64 cement kilns in Germany, 21 used SNCR to control NO_x and nine facilities were equipped with staged combustion.^{vii} This was an increase from 15 SNCRs and seven facilities with staged combustion reported the previous year.

5.2 Emission Limits for SO₂

In the U.S. there are no federal or state regulations that apply emission limits for SO₂ for cement kilns. In some cases, emission limits have been applied to specific facilities as part of the permit application process.

In Europe, the top of stack emission limits for SO₂ have been applied in most EU countries to the cement sub-sector. In Germany, limits have been set for both new and existing facilities. As a result, in 2001 of the 64 cement kilns in Germany, 11 used absorbent addition to control SO₂.^{viii}

6 Costs for Emission Reductions

In the cement sub-sector there is a large variation between facilities with respect to the age of equipment, the type of kilns and the degree to which facilities have modernized. As a result, individual control technologies may only be applicable to some facilities or may require a range of modifications to the equipment at the facilities. Consequently, during the study and consultations there was a wide range of costs reported and reduction efficiencies estimated. The range of costs summarized below incorporate these variations. As an illustration of the range of costs, two facilities that installed low NO_x burners reported very different actual capital costs; one at one million and the other over \$15 million. There is additional uncertainty around the estimated costs for SNCR and wet scrubbing due to limited experience in the application of these technologies to this sub-sector. There is considerable uncertainty around the costs and effectiveness of absorbent addition and there has only been limited use of this technology and its reported effectiveness has varied widely depending on process conditions unique to each facility. Tables B-6 and B-7 provide a summary of the range of emission reductions for the more common control technologies

used by this sub-sector. The percent reductions in Tables B-6 and B-7 are for all cement sub-sector emissions.

Table B-6: Emission Reductions and Costs of NO_x Control Technologies for the Cement Sub-sector

Technology	Reduction from 2000 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of NO _x removed)
	(%)	(kt)	(\$ Millions)			
LNB	10-47	0.7-2.2	9-24	2.2-5.5	3.0-7.6	1,400-10,500
SNCR	10-50	1.1-5.6	17-39	11-12	13-15	2,400-13,500
Process Controls	0-20	0-1.2	56-59	8.5-9.8	13-15	11,000-25,000

LNB – Low NO_x Burners; SNCR – Selective Non-Catalytic Reduction

Table B-7: Emissions Reductions and Cost of SO₂ Control Technologies for the Cement Sub-sector

Technology	Reduction from 2000 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of SO ₂ removed)
	(%)	(kt)	(\$ Millions)			
Wet Scrubbing	90- 95%	21- 22	77-130	6.1-32	13-43	600-3,800
Absorbent Addition	10- 80%	1.6- 13	3.3-4.5	2.0-8.0	2.3-8.3	170-5,100

Appendix C: Glass

1 Overview of the Glass Sub-sector

In the glass manufacturing sub-sector there are two manufacturers of primary glass in Ontario, operating a total of four facilities. Three of these facilities are operated by O-I Canada Corp. (formerly Consumers Glass) and produce container glass for the beverage, food, pharmaceutical, etc. industries. The fourth facility (operated by PPG Canada) produces flat glass for the automotive industry. The companies, facilities, and type of glass produced are shown in Table C-1.

The flat glass facility is the main interest of this study, since in 2001 it accounted for over 60% of the glass manufacturing sub-sector's nitrogen oxides (NO_x) emissions, and it is the only glass facility that emits greater than 1.5 kt of NO_x annually. Emissions of SO₂ were not studied since all glass facilities combined emit less than 1.0 kt of SO₂ annually.

Table C-1: Ontario's Glass Production Facilities

Company	Manufacturing Location	Glass Type
PPG Canada Inc.	Owen Sound, ON	Flat Glass
O-I Canada Corp.	Brampton, ON	Container Glass
	Milton, ON	Container Glass
	Toronto, ON	Container Glass

2 Production Process Description

Most commercial glass is composed of soda, lime and silica. The main raw ingredient used in the production of glass is silica. Due to the high melting temperature of silica, soda is added to reduce the melting temperatures to a more workable level. Lime is added to increase the durability of the glass. There are five main steps required in the production of glass, specifically: mixing, melting, forming, annealing, and finishing.

The raw materials are proportioned, mixed and then melted in natural gas fired furnaces. Most commercial glass is melted in continuous regenerative furnaces that are able to recover waste heat from combustion exhaust gases. Once the raw materials have been melted, the molten glass is transferred to the forming operation. Flat glass is typically formed using the float process. Molten glass is fed as a continuous ribbon into a bath of molten tin where it floats and is fire polished. The ribbon of glass is then transferred from the float bath to an annealing oven where it is gradually cooled to prevent cracking. After it

has been cooled, the glass is cut. The glass is then often coated with thin layers of metal or chemical compounds that absorb infrared light or improve the reflecting qualities of glass.

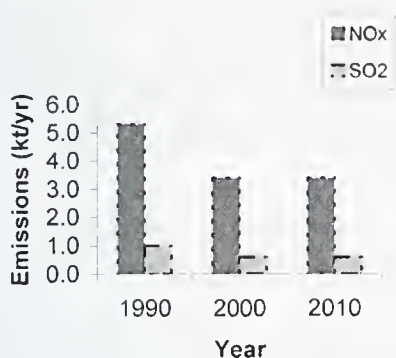
3 Emissions

3.1 Emission Sources

The primary NO_x emission source within these facilities is the glass melting furnaces. NO_x emissions are generated from the combustion of natural gas in the furnaces.

3.2 Emission Trends

Figure 3: NO_x and SO₂ Emissions Trends - 1990, 2000 and Projected 2010 Emissions



Total emissions of NO_x from 1990 to 2000 from flat glass and container glass facilities have decreased 37% from 5.4 to 3.4 kt. The majority of the emission decreases have come through facility closures, including the AFG Industries Ltd. flat glass facility in Scarborough and the Consumers Glass Inc. container glass facility in Hamilton.

3.3 Estimating Emissions

NO_x emissions for the one flat glass producer remaining in Ontario are based on the results of stack testing. No continuous emission monitors are in place.

4 Emission Reduction Technologies

4.1 NO_x Control Options

The main options available to reduce NO_x emissions from flat glass melting furnaces are shown in Table C-2.

Table C-2: NO_x Control Techniques Applicable to Glass Furnaces

Technology	NO _x Emission Reduction	Remarks
Low Excess Air	0-10%	Low cost, easily implemented option. However, only limited reductions are possible and reductions may be negligible if furnace is already operating within the range for low excess air.
Oxy-Fuel Melting	70-75%	The Oxy-Fuel control option uses oxygen to replace combustion air. It is a relatively new technology and has been installed only at a few facilities in the U.S., including on two U.S. PPG furnaces in 2000 and 2002. Based on its experience, PPG estimates cost effectiveness at \$2,600/tonne NO _x removed.
3R Process	60-70%	The 3R Process chemically treats the exhaust gas by adding fuel. It is a relatively new technology and has been required in recent BACT determinations for flat glass facilities. The cost effectiveness was reported by one facility to be US\$ 1,044/ton NO _x removed. The 3R Process increases fuel consumption and corresponding CO ₂ emissions by approximately 15%.
SNCR	30-40%	The two flat glass facilities identified that implemented SNCR in the U.S. have switched to other control techniques due to operational problems encountered with the use of SNCR.

With the exception of low excess air, the other control technologies listed in Table C-2 can only be installed during a "cold repair" which takes place every 10-12 years. Between major repairs the furnace operates continuously, making major modifications impossible without an unscheduled shutdown.

5 Emission Limits in Other Jurisdictions

5.1 Emission Limits for NO_x

In the United States, glass furnaces were specifically exempted from the NO_x SIP Call as they did not identify any cost control measures at the time that was below their US\$ 2000 cost effectiveness criteria.

New or modified flat glass furnaces in the U.S. that have been subject to Prevention of Significant Deterioration (PSD) permit requirements have recently been required to install the 3R Process as part of their BACT determination.

6 Costs for Emission Reduction

Costs for control technologies shown in Table C-3 were based on data provided by the glass sub-sector. Where applicable, costs were scaled based on production capacity.

Table C-3: Emission Reductions and Costs of NO_x Control Technologies for the Glass Sub-sector

Technology	Emission Reduction from 2000		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of NO _x removed)
	(%)	(kt)	(\$ Millions)			
Low Excess Air	0-6%	0-0.2	N/A	Already implemented		N/A
3R Process	38-44%	1.3-1.5	15	1.4	2.4	\$1,600-\$1,800
SNCR	18-24%	0.6-0.8	15	0.4	1.4	\$1,800-\$2,300
Oxy-Fuel	44-47%	1.5-1.6	12	2.8	3.5	\$2,200-\$2,300

SNCR – Selective Non-Catalytic Reduction

Appendix D: Iron and Steel

1 Overview of Iron and Steel in Ontario

Ontario has four integrated steel mills (where iron ore is reduced with coke to liquid iron in a blast furnace and converted to steel in a basic oxygen furnace (BOF)) and five mini-mills (where steel scrap is converted to steel in an electric arc furnace (EAF)). Canadian steel production, for which Ontario is the major producer, has grown 30% from 1990 to 1999. Most of this sub-sector's growth over the last two decades can be attributed to the increased production of steel by mini-mills. The integrated mills are the focus of the study, since they account for over 90% of the iron & steel sub-sector's nitrogen oxides (NO_x) and sulphur dioxide (SO₂) emissions in Ontario. The integrated steel mill companies, locations and capacities are listed in Table D-1.

Table D-1: Ontario Integrated Steel Mills^{ix}

Company	Location	Steel Production Capacity (Mt/yr)
Algoma Steel Inc.	Sault Ste. Marie	2.27
Dofasco Inc.	Hamilton	3.75*
Stelco Inc. – Hilton Works Div.	Hamilton	2.42
Stelco Inc. – Lake Erie Steel Co. Div.	Nanticoke	2.10
Total		10.54

* includes 2.4 Mt of BOF capacity and 1.4 Mt of EAF capacity

2 Production Process Description^x

"Integrated" steel mills refer to the integration of iron making and steel making in the same facility. Conventional integrated steel mills use blast furnaces to reduce iron ore pellets to molten pig iron in a continuous process. There are five blast furnaces used by the four integrated steel mills. One integrated mill uses a sinter facility to agglomerate iron-bearing mill wastes and iron ore fines prior to charging to the blast furnace. Coke, a relatively pure form of carbon, is used as the reductant (and energy source) in the blast furnaces along with blasts of hot air. Other fossil fuels such as oil or natural gas are also used to supplement the carbon supply in the blast furnaces. Coke is produced on-site from coal in coke ovens. There are a total of 11 coke oven batteries used by the four integrated steel mills. Coke by-product facilities condition coke oven gas to make the gas usable as a fuel in the mills.

Pig iron is desulphurized and then refined in batches in a basic oxygen furnace (BOF) to produce liquid steel. The carbon content of the pig iron is reduced by oxidation in the BOF. There are a total of eight basic oxygen furnaces operated at the four Ontario integrated steel mills. A full range of high quality steels can be produced in integrated steel mills because there is control over the materials and steel composition at all stages of production.

Electric arc furnaces (EAF's) are smaller, less capital-intensive operations that melt recycled scrap steel to produce steel products. Dofasco is the only integrated steel mill with an EAF. Since there is little carbon content in scrap steel, an electric arc is used to provide most of the energy for liquid steel production. No coal or coke is used in an EAF but oxy-fuel burners that use natural gas or oil can be used to provide combustion heat to supplement the electric energy.

After the raw steel is produced in a BOF or an EAF, final metallurgy adjustments are made in a ladle metallurgy furnace before being cast into intermediate products. Conventionally, these intermediate products are cooled and stored in inventory before further milling.

Milling operations can be categorized into hot rolling and finishing stages. Conventional hot rolling operations use rehear furnaces to heat the intermediate steel products to allow further milling (e.g., hot rolling) into the final product. Finishing operations include cold mills, wire mills, galvanizing (zinc coating) and tin plating lines. An integrated steel mill would typically have all of these operations. Auxiliary utilities in a steel mill include boilers and can include an oxygen facility.

3 Emissions

3.1 Emission Sources

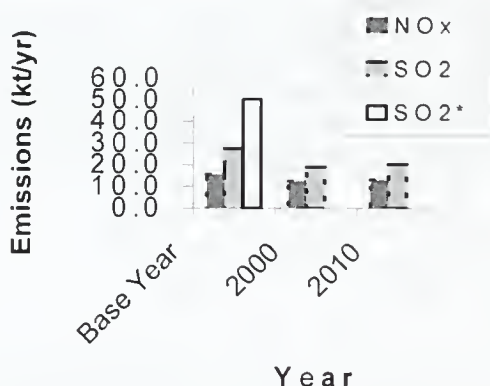
The iron and steel sub-sector has undertaken a third party review of their NO_x and SO₂ emissions. The following analysis is based on these emission data for the integrated iron and steel sub-sector.

The principal sources for NO_x and SO₂ emissions and the percent emissions contributions by integrated mill process are summarized in Table D-2. Most NO_x and SO₂ emissions come from fuel combustion throughout the mills.

Table D-2: Integrated Iron & Steel Sub-sector Share of Emissions by Process Type

		Coke Making	Iron Making	Utility Boilers	Hot Rolling (Reheat Furnaces)	Steel Making
NO _x Emissions	Average	24%	24%	18%	16%	10%
	Range	8-38%	7-46%	14-27%	9-24%	8-14%
SO ₂ Emissions	Average	48%	13%	25%	12%	0%
	Range	39-53%	3-28%	20-27%	2-26%	0%

3.2 Emission Trends

Figure 4: NO_x and SO₂ Emissions Trends - Base Year+, 2000 and Projected 2010 Emissions

*Emissions of SO₂ from the now closed Algoma Sintering Facility in Wawa

* Base Year is year closest to 1990 with representative emissions

3.2.1 NO_x Trends

The emissions of NO_x from the integrated iron and steel sub-sector represented approximately 3% of Ontario's emissions in 2000. Total annual emissions of NO_x from Base Year (year closest to 1990 with representative emissions) to 2000 decreased 17% from 15.2 to 12.6 kt. The sub-sector has predicted a further reduction of 0.7 kt by 2010 for a total NO_x reduction of 25% from Base Year levels. These decreases were mostly due to process improvements leading to more efficient use of fuel, the installation of low-NO_x burner systems, careful control of oxygen levels where possible and a number of unit shutdowns over the period.

3.2.2 SO₂ Trends

The emissions of SO₂ from the integrated iron and steel sub-sector represented approximately 4% of Ontario's emissions in 2000. Total annual emissions of SO₂ from Base Year to 2000 decreased by 34% from 28.2 to 18.5 kt. The sub-sector has predicted a further reduction of 3 kt by 2010 for a total reduction in SO₂ of 37% from Base Year levels. Additional reductions of SO₂ emissions of 50.3 kt from Base Year occurred due to the closure of Algoma Steel's sintering facility in Wawa. Including these emissions, there has been a reduction in SO₂ emissions of 60.0 kt or 76% from Base Year levels to 2000.

3.3 Emissions Estimation

Emissions are estimated using a variety of techniques. No sources in the iron and steel sub-sector are known to be equipped with continuous emission monitors. In the four integrated steel mills there are a total of 32 sources that have reported heat inputs greater than 250 million Btu/hr. Eleven of these sources are utility boilers.

Currently, revised emission estimates provided by the sub-sector are being reviewed. Historic, current and projected emission estimates could be modified to reflect these changes.

4 Emission Reduction Technologies

There are several different technologies and practices that can be applied to control emissions of NO_x and SO₂ from integrated steel mills. Tables D-3 and D-4 summarize the major sources, combustion modification and post-combustion control technologies used to reduce NO_x and SO₂ from integrated steel mills. Generally applicable technologies, such as low NO_x burners, are not shown here, but are used in the cost analysis that follows.

4.1 NO_x Control Options

Table D-3: NO_x Control Technologies and Approaches Applicable to the Integrated Iron & Steel Sub-sector

Technology	Applicable To	Emission Reduction	Remarks
Process Modifications & Energy Efficiency Improvements	All sources	Varies	Using less fuel reduces the generation of NO _x . Each facility will have different opportunities for optimizing processes and equipment to reduce fuel consumption.

4.2 SO₂ Control Options

Table D-4: SO₂ Control Technologies Applicable to the Integrated Iron & Steel Sub-Sector

Technology	Applicable To	Emission Reduction	Remarks
Post-combustion controls			
Limestone Forced Oxidation (LSFO)	Blast Furnace Stoves Coke Oven Underfiring Reheat Furnaces	95%	This technology has not been used in this sub-sector. In addition, LSFO has a much higher estimated cost than Coke Oven Gas (COG) Desulphurization.
Lime Spray Drying (LSD)	Blast Furnace Stoves Coke Oven Underfiring Reheat Furnaces	90%	This technology has not been used in this sub-sector. In addition, LSD has a much higher estimated cost than COG Desulphurization.
Alternative Approaches			
Coke Oven Gas (COG) Desulphurizing	Affects any source burning undesulphurized COG ^a	90% sulphur removal from COG ^b	One mill currently desulphurizes approximately 50% of its COG.
Fuel Switching	All Combustion Equipment ^c	Varies	By switching to a lower sulphur fuel, facilities can reduce SO ₂ emissions.

^a e.g. coke ovens, blast furnaces, boilers, reheat furnaces

^b COG desulphurization would reduce overall facility SO₂ emissions from 40% to 80% (unweighted average of 60%)

^c only applicable to combustion equipment burning undesulphurized coke oven gas, oil or blast furnace gas

4.3 Other Technologies

A few significant energy savings or emission reduction technologies that are commercially available are described below for reference, but require the right economic conditions before they can be implemented. Costs for the following technologies were not developed.

Fossil Fuel Injection

The injection of fossil fuels directly into the blast furnace as supplementary reductants can reduce the overall requirement for coke production and associated NO_x and SO₂ emissions. This is practiced to varying degrees in most integrated steel mills in Ontario.

Thin Slab Casting

A major advance in casting that produces a continuous slab 1-2 inches thick compared to a conventional slab thickness of 8-10 inches. This technology offers the direct connection of liquid steel production to hot sheet rolling, saving losses from reheating and requiring less milling energy. Currently one mill uses this technology to cast some of its steel and directly produce hot strip steel.

BOF Gas Recovery

BOF exhaust gas contains carbon monoxide (CO) that is produced from the oxidation of carbon in the hot metal. Most North American integrated steel producers flare BOF exhaust gases and do not recover the energy, because low fuel prices make it uneconomic. BOF Gas Recovery systems generate steam by recovering the residual heat from the BOF gas and combusting the CO content. None of the Ontario integrated steel mills are believed to have BOF Gas Recovery systems installed. BOF Gas Recovery systems are more commonly installed in Europe where fuel prices are higher.

Co-generation

Co-generation (generating steam and electricity) is a technology that could potentially reduce overall fuel energy consumption and the associated emissions (if replacing inefficient boilers and/or displacing higher-emission electricity generation). Electric power could be used internally or sold to the electricity distribution grid.

Alternative Iron Making Processes

Alternative iron making processes that eliminate the need for sintering and coke-making offer the most promising multi-pollutant reduction approach for the steel sub-sector. The two general types of alternative iron-making processes are smelting-reduction processes and direct iron ore reduction processes. There are several smelting-reduction processes in early stages of commercialization that use coal to directly reduce iron ore to pig iron. The process is more energy efficient (uses 20-30% less energy than conventional iron production) because coke manufacturing is eliminated. The production of direct reduced iron (DRI) using natural gas offers a process that has comparable energy consumption to smelting-reduction.

5 Emission Limits in Other Jurisdictions

5.1 Emission Limits for NO_x

In the U.S., there are no limits for NO_x at the federal level for the iron and steel sub-sector beyond the new source performance standards (NSPS) for new or modified boilers and the application of the NO_x SIP Call to large boilers in affected areas. At the local level, most facilities are regulated by the limits in their site specific operating permits.

5.2 Emission Limits for SO₂

There are no limits in the U.S., at the federal level, for SO₂ from the iron and steel sub-sector beyond the new source performance standards (NSPS) for new or modified boilers. At the local level, SO₂ at most facilities is regulated by the limits in their site specific operating permits. Pennsylvania has more coke oven batteries (17) than any other state and has state legislation that requires SO₂ emissions from coke oven batteries be controlled. This is done by limiting the concentration of H₂S in the coke oven gas to 50 grains/100 ft³ prior to flaring or combustion of the coke oven gas.

6 Costs for Emission Reductions

Tables D-5 and D-6 were prepared based on the results of costing conducted and using the main references cited at the end of this report. Where applicable, costs were scaled based on production capacity. The percent reductions in Tables D-5 and D-6 are for all integrated iron and steel sub-sector emissions.

Low Excess Air (LEA), Low NO_x Burners (LNB) and Selective Catalytic Reduction (SCR) are applicable to most combustion sources in this sub-sector. LEA and LNB are well understood by this sub-sector and are commercially available. The sub-sector has no experience with the use of SCR to reduce NO_x emissions.

The cost ranges in Tables D-5 and D-6 reflect industry comments and the approximate degree of uncertainty due to cost estimating techniques. In addition, there is significant uncertainty as to the sub-sector-wide reduction potential of lowering excess air since individual sources may already have excess air levels controlled to the lowest practical levels. In this case, the reduction potential in Table D-5 would be overestimated and the corresponding cost per tonne of NO_x removed would increase. There is also uncertainty around the estimated costs for SCR due to very limited experience in the application of this technology to this sub-sector.

Table D-5: Emission Reductions and Costs of NO_x Control Technologies for the Integrated Iron & Steel Sub-Sector

Technology	Reduction from 2000 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of NO _x removed)
	(%)	(kt)	(\$ Millions)			
LEA	4 - 9	0.5 -1.2	\$5.0 - \$7.5	\$0.1	\$0.5 - \$0.7	\$400 - \$600
LNB	9 - 15	1.1 - 1.9	\$31 -\$88	\$0.7 - \$1.9	\$3.4 - \$9.5	\$2,700 - \$7,500
SCR	55 - 65	6.9 - 8.2	\$271 - \$407	\$30 - \$45	\$53 - \$80	\$7,300 - \$11,000

LEA- Low Excess Air; LNB – Low NO_x Burners; SCR – Selective Catalytic Reduction**Table D-6: Emission Reductions and Costs of SO₂ Control Technologies for the Integrated Iron & Steel Sub-sector**

Technology	Reduction from 2000 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of SO ₂ removed)
	(%)	(kt)	(\$ Millions)			
Coke Oven Gas Desulphurization	59 - 62	10.9 - 11.4	\$158 - \$209	\$7.9 - \$10.5	\$22 - \$29	\$2,000 - \$2,600

Appendix E: Non-ferrous Smelting

1 Overview of the Non-ferrous Smelting Sub-sector in Ontario

The Non-Ferrous Smelting sub-sector is made up of four primary metal smelting and refining facilities and two secondary (recycled) lead smelting facilities.⁵ The sub-sector produces copper, nickel, zinc, cobalt, recycled lead, and some other metals.

Only the two largest smelting/refining facilities operated by Inco Ltd. and Falconbridge Ltd. were examined in this study. Over 90% of Ontario's non-ferrous metal production come from Inco (Sudbury) and Falconbridge (Falconbridge and Kidd Creek), which are the major emitters of sulphur dioxide (SO₂) in Ontario, contributing 42% of Ontario's SO₂ emissions. Collectively, Inco and Falconbridge emit virtually all of the SO₂ from the non-ferrous sub-sector. These facilities are required by Ontario Ministry of the Environment Control Orders to reduce their annual SO₂ emissions by 34% below their 1994 regulated limits by 2007. Smelting and refining capacity in 2001 for Inco and Falconbridge are listed in Table E-1.

Table E-1: Ontario Smelting & Refining Production Capacity, 2001^{xi}
(kilotonnes per year)

Operation	Company	Location	Copper	Nickel	Zinc
Smelting	Inco Ltd.	Sudbury	135	100	
	Falconbridge Ltd.	Falconbridge	23	70	
	Falconbridge Ltd.	Timmins	140		145
	Total Ontario Capacity		298	170	145
Refining	Inco Ltd.	Copper Cliff	140	59	
	Falconbridge Ltd.	Timmins	147		145
	Total Ontario Capacity		287	59	145

⁵ The primary facilities are: INCO Ltd. (Sudbury and Pt. Colborne), Falconbridge Ltd. [Falconbridge (Sudbury) and Kidd Creek (Timmins)]. The secondary lead facilities are Tonolli Ltd. (Mississauga) and Canada Metal Ltd. (Mississauga).

2 Production Process Description

The production cycle for primary non-ferrous metals in Ontario include four main stages: mining, milling, smelting and refining. Non-ferrous metal mining operations remove ore from underground metal-rich deposits. Ore containing 2 to 10% metal is crushed and ground then separated through a flotation operation into a concentrate containing 40-60% metal. Ore concentrate is smelted with oxygen at high temperatures to convert the metal (usually present in a sulphide form) to a matte form, containing over 95% of metal in an elemental state. In the smelting process, the sulphur in the ore is converted to SO₂, most of which is recovered as sulphuric acid. The refining process purifies smelted product into high-purity (>99.5%) metal, which can be shipped in various forms (powders, pellets, slabs formed products, etc.).

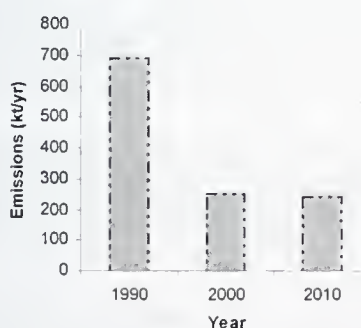
3 Emissions

3.1 Emission Sources

The three energy-intensive non-ferrous smelting operations are the major sources of SO₂ in this sub-sector. Refining operations currently do not contribute significantly to total emissions of SO₂.

3.2 Emission Trends

Figure 5: SO₂ Emissions Trends - 1990, 2000 and Projected 2010 Emissions



3.2.1 NO_x Trends

The emissions of nitrogen oxides from this sub-sector represent approximately 0.3% of Ontario's emissions in 2000. Both of the major smelting and refining companies in Ontario have applied management programs aimed at reducing electricity and fossil fuel use and emissions. This report does not consider NO_x emissions or reductions strategies further, due to the relatively low NO_x emissions from this sub-sector (two kt in 1999).

3.2.2 SO₂ Trends

The emissions of sulphur dioxide from this sub-sector represent approximately 42% of Ontario's emissions in 2000. Total emissions of SO₂ from 1990 to 1994 decreased 62% from 693 to 222 kt. From 1994 to 2001, SO₂ emissions rose to 260 kt. Due to current Control Orders, sub-sector emissions are expected to be no higher than 245 kt by 2010 for a total reduction in SO₂ of at least 65% from 1990 levels.

The majority of SO₂ emissions come from nickel/copper smelting in the two Sudbury smelters. The nickel production trend has remained relatively stable from 1990 to 2000. Copper production has declined by about 20%. Zinc production has declined by 66% since 1990.^{xii} No significant new non-ferrous metal operations have been added in Ontario in the last 10 years.

The large decrease in SO₂ emissions from 1990 is mainly due to continued efforts to increase the capture efficiency of SO₂ from various sources. The most significant change occurred at the sub-sector's largest source of SO₂ emissions: a new, state-of-the-art, oxygen flash-smelting process was installed in 1994 at Inco's Copper Cliff smelter along with increased sulphuric acid facility capacity.

3.3 Estimating Emissions

Emissions of SO₂ are estimated using mass balance techniques. Both Inco and Falconbridge have SO₂ continuous emission monitors but they are not used for annual emission estimation reporting.

4 Emission Reduction Technologies

4.1 SO₂ Control Options

Control technologies have already been installed by Ontario facilities over the past number of years. A summary of SO₂ control technologies was developed for Environment Canada's Strategic Options Process (SOP) in 1997 and is presented in Table E-2.

Table E-2: Ontario Non-ferrous Metal Smelters and Refineries, Their Processes and SO₂-related Environmental Control Technologies^{xiii}

Company	Location/facility	Processes	Control Systems in Place
Falconbridge	Kidd – Copper Smelter	Mitsubishi Continuous Smelting and Converting Furnace	Electrostatic Precipitators (gas conditioning), Acid Facility

Company	Location/facility	Processes	Control Systems in Place
	Kidd – Zinc Refinery	Roast-Leach, Pressure Leach, Electrowinning	Electrostatic Precipitators (gas conditioning), Wet Scrubbing, Acid Facility, and Effluent Treatment
	Sudbury Nickel/Copper Smelter	Fluid Bed Roasting, Electric Furnace Smelting, Converting	Electrostatic precipitators (gas conditioning), Acid Facility, Weak Acid Neutralization
INCO	Sudbury Nickel/Copper Smelter	Smelter Flash Smelting and Converting, Fluid Bed Roasting and Finishing Converting	Electrostatic Precipitators (gas conditioning), Acid Facility and Liquid SO ₂ Production
	Sudbury Nickel Refinery	Top Blown Rotary Converter (TBRC) Smelting	Electrostatic Precipitators

5 *Emission Limits in Other Jurisdictions*

5.1 Canadian Emission Limits

Since 1994 Environment Canada has been engaged in a Strategic Options Process (SOP) to address emissions of pollutants considered toxic under the criteria set out in the Canadian Environmental Protection Act (CEPA). The first set of 44 pollutants was set out in the Priority Substances List (PSL) and 14 "Issue Tables" were established to address the control of these substances.

The Issue Table for the non-ferrous sub-sector's SOP was a multistakeholder consultative group including representatives from Environmental Non-Government Organizations (ENGO's), industry, First Nations, provincial/territorial governments and other federal government departments as well as Environment Canada.

A final report providing the recommendations arising from the Base Metal Smelting Sub-sector SOP was produced in April 1999. Since then, Environment Canada has drafted a Code of Practice addressing releases of PSL pollutants and other pollutants, notably sulphur dioxide and particulate matter. A revised draft Code of Practice was presented to a multistakeholder workshop held in Hull, Québec in February 2003.

Many requirements in the draft Code of Practice are administrative in nature (e.g., establishment of ISO 14000 Environmental Management System, setting of facility-specific Environmental Performance Indicators), and the Code will be a voluntary compliance initiative. However, Environment Canada is required to track the effectiveness of the final

Code as an instrument under CEPA and significant deviations from the final Code may lead to development of other instruments such as regulations.

The draft Code of Practice includes specifications for capture or fixation of sulphur present in feed materials rather than an emission limit for sulphur dioxide. The draft Code recommends each smelter facility should be designed, constructed and operated to achieve 90% containment of sulphur in feed as the emission guideline for sulphur dioxide.

5.2 International Emission Limits

Fifteen countries other than Canada were identified as having nickel smelters, however, few have more than one facility. Due to the small number of facilities in each country, emission limits for nickel smelters were found to be set on a case-by-case basis, usually through the environmental assessment and/or permitting process. The United States ceased production of nickel in 1998.

6 Costs for Emission Reduction

Costs for control technologies were based on data provided by the sub-sector and in a technical report.^{xiv, xv, xvi} Table E-3 provides a summary of emission reductions and costs for selected control technologies that may be applicable to this sub-sector.

Table E-3: Emission Reductions and Costs of SO₂ Control Technologies for the Non-ferrous Metals Sub-sector

	Capital Cost (\$ Millions)	Annual Operating & Maintenance Cost (\$ Millions)	Annualized (\$ Millions)	kt reduced	\$/ tonne
Inco Copper Cliff Fluid Bed Roaster Off-gas Control	\$100	\$3	\$12	90	\$130
Inco Copper Cliff Continuous Converting Technology ^a	\$480	\$9	\$50	110	\$456
Falconbridge Sudbury Acid Gas Scrubbing	\$80	\$8	\$15	29	\$500

	Capital Cost (\$ Millions)	Annual Operating & Maintenance Cost (\$ Millions)	Annualized (\$ Millions)	kt reduced	\$/ tonne
Inco Copper Cliff Secondary capture hoods on converters and multi purpose vessels/acid facility expansion/ducting changes on flash furnace ^a	\$660	\$22	\$78	108	\$700

^a Only one option (Secondary capture hoods, etc. OR Continuous Converting) can be implemented

Appendix F: Petroleum Refining

1 Overview of the Petroleum Refining Sub-sector in Ontario

The Petroleum Refining sub-sector is made up of seven facilities in Ontario operated by five companies as listed in Table F-1. Seventy-six per cent of production is made up of fuel products used throughout the economy. Non-fuel products (lubricating oils, greases, asphalt, etc.) and petrochemical feedstock make up the remainder. Fuel products are made at six facilities, one facility also refines crude oil into chemical feedstock and one facility produces lubricant base stocks from light and heavy fuel oils.

Table F-1: Petroleum Refineries in Ontario^{xvii}

Company	Location	Raw Material Processing Capacity (crude or lubricants feed)
		(barrels per day)
Imperial Oil Ltd.	Nanticoke, ON	112,000
Imperial Oil Ltd.	Sarnia, ON	120,800
Nova Chemicals (Canada) Ltd.	Corunna, ON	80,000
Petro-Canada Inc.	Mississauga, ON	23,000 ^{xviii}
Petro-Canada Inc.	Oakville, ON	83,000
Shell Canada Products Ltd.	Corunna, ON	71,400
Suncor Energy Products Inc.	Sarnia, ON	78,000
Total		568,200

The refineries in Ontario represent approximately 30% of Canadian crude oil capacity. The majority of the refineries are situated in the Sarnia area. Two of the other refineries are located in the Greater Toronto Area and one in Nanticoke.

2 Production Process Description

The petroleum refining process transforms crude oil into a variety of petroleum products that can be used for fuels, petrochemical feedstocks, lubricants, and asphalt. Simply stated, petroleum refining combines distillation processes (separation into various fractions)

with other processing operations that alter the molecular structure of hydrocarbons. Simplified process steps are briefly described below.

The first phase in petroleum refining operations is the separation of crude oil into its major constituents using three petroleum separation processes: atmospheric distillation, vacuum distillation, and light ends recovery. Once separated, these constituents can be converted to gasolines and other light fractions. Larger petroleum fractions are broken down into smaller ones through catalytic cracking, coking, and visbreaking processes.

These larger fractions, in turn, can be reformed or combined to produce higher-value molecules of similar or larger size. Treating processes can remove undesirable impurities such as sulphur, nitrogen, and oxygen through hydrodesulphurization, hydrotreating, chemical sweetening, and acid gas removal.

3 Emissions

3.1 Emission Sources

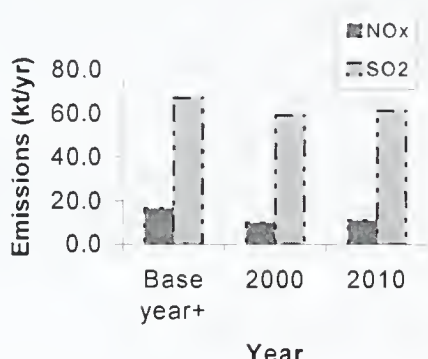
The main sources of nitrogen oxides (NO_x) are the process heaters/furnaces, utility boilers and the Fluidized Catalytic Cracking Units / carbon monoxide boilers (FCCU/CO boilers). The main sources of sulphur dioxide (SO₂) are the sulphur recovery units, utility boilers and FCCU/CO Boilers. Table F-2 shows the contribution to sub-sector emissions by equipment type and also shows the range of emission contributions by main equipment type based on facility-specific emission inventories.

Table F-2 Emission Contributions by Equipment Type – NO_x and SO₂

Equipment Type	Equipment Contribution to Facility Emissions		Equipment Contribution to Sub-sector Emissions	
	NO _x	SO ₂	NO _x	SO ₂
Utility Boilers	11-98%	6-69%	25%	20%
Process Heaters & Furnaces	2-79%	0-73%	39%	14%
FCCU/CO Boilers	0-48%	0-41%	23%	30%
Sulphur Recovery Units	N/A	0-54%	0%	35%
Other	N/A	N/A	13%	1%

3.2 Emission Trends

Figure 6: NO_x and SO₂ Emission Trends - Base Year+, 2000 and Projected 2010 Emissions



* Base Year is 1990 for NO_x emissions and 1994 for SO₂ emissions

3.2.1 NO_x Trends

The emissions of nitrogen oxides from this sub-sector represent approximately 2% of Ontario's emissions in 2000. NO_x emissions declined by 38% between 1990 and 1999, from 18.4 to 11.4 kt, mostly due to energy efficiency measures that resulted in overall reductions in fuel consumption, as well as low NO_x burners installed on some process heaters and boilers. NO_x emissions are forecasted by the sub-sector to increase to 13.4 kt by 2010, partly due to the anticipated increase in energy required to lower the sulphur content of gasoline and diesel fuel.

3.2.2 SO₂ Trends

The emissions of sulphur dioxide from this sub-sector represent approximately 11% of Ontario's emissions in 2000. Total emissions of SO₂ from 1994 to 1999 decreased 11% from 67.1 to 59.7 kt. Increased recovery of sulphur from sour-gas streams is an example of process improvements that have contributed to these reductions. The sub-sector has predicted an increase in SO₂ emissions to 66.5 kt by 2010 if no additional actions are taken which is only 1% below 1994 levels. The projected SO₂ emissions increase results from a projected increase in the combustion of refined petroleum products.

3.3 Estimating Emissions

Emissions are estimated using a variety of techniques. Only one source in the sub-sector is currently equipped with a continuous emission monitor. In the seven petroleum refining facilities there are a total of 12 sources that have heat inputs greater than 250 million

Btu/hr. Eight of these sources are utility boilers, two are FCCU/CO boilers and two are process heaters.

The sub-sector is currently undertaking a National Framework for Refinery Emission Reductions which will involve establishing national, provincial and facility-level benchmarks for air emissions of NO_x, SO₂, VOC, CO, PM and benzene. The benchmarking exercise will assist Ontario in better understanding performance and efficiency of the sub-sector relative to their U.S. counterparts.

4 Emission Reduction Technologies

4.1 NO_x Control Options

Emission controls applicable in the petroleum sector to reduce NO_x emissions are those commonly applied to fossil fuel combustion as listed in Table 1 and are not repeated here. Most of the combustion control techniques (LEA, LNB, OFA and FGR) are well understood by this sub-sector and are commercially available. The sub-sector has limited experience with the use of SNCR and SCR to reduce NO_x emissions from FCCU/CO boilers.

4.2 SO₂ Control Options

Within the petroleum sub-sector, the control options include energy efficiency/conservation measures, wet gas scrubbing, DeSO_x catalyst on FCCU/CO boilers, and the use of tail gas treatment on the sulphur recovery units. The applicability of several emission control techniques is described in Table F-3.

Table F-3: SO₂ Control Techniques Applicable to the Petroleum Refining Sub-Sector

Control Technology	Acronym	% Emission Reduction	Remarks
Energy Efficiency/Conservation Measures	EE/EC	Varies	Using less fuel reduces SO ₂ generation. Each facility will have different opportunities for optimizing processes and equipment to reduce fuel consumption.
Fuel Switching	FS	Limited	Reduction due to fuel switching in the petroleum sub-sector is limited as the avoided fuel would then be sold and burned by another facility with no net decrease in emissions.

Control Technology	Acronym	% Emission Reduction	Remarks
Dry Flue Gas De-sulphurization	Dry FGD	55-95%	It is reported that using Dry FGR to control FCCU emissions can lead to long-term reliability problems because of the build-up of sludge/solids. In addition this technology has a much higher estimated cost than other control technologies available to this sub-sector.
Wet Gas Scrubbing	WGS	90-98%	WGS removes particulates and SO ₂ by scrubbing them from the FCCU/CO boiler flue gas through contact with an aqueous solution. This technology is generally applied to the FCCU/CO boilers in this sub-sector. It is available commercially and is in use at a number of U.S. facilities.
DeSOx Catalyst Additives	DeSOx	30-50%	The SO ₂ in the FCCU overhead can be reduced by using a metal-oxide additive added to the FCCU reactor catalyst. The additive converts the sulphur from S and SO ₂ to H ₂ S. The H ₂ S is then recovered as elemental sulphur using a conventional sulphur recovery system.

5 Emission Limits in other Jurisdictions

The U.S. EPA has a federal strategy for achieving cooperative, across-the-board compliance by major U.S. refining companies. Under this strategy the U.S. EPA has entered into consent decrees with seven companies that represent over 50% of the U.S. refining capacity.

The consent decree of the largest refining company in the U.S., Marathon Ashland Petroleum LLC, was reviewed to identify the NO_x and SO₂ control measures being required. Marathon operates refineries in seven states with a collective capacity of 935,000 barrels of oil a day and represents more than 5% of the U.S. domestic refining capacity. Under the consent decree Marathon will be required to:

1. spend nearly US\$ 265 million over eight years (2001-2009) to reduce NO_x and SO₂ emissions by 8,000 tons and 12,800 tons/year respectively
2. pay a civil penalty of US\$ 3.8 million
3. install equipment to control NO_x and SO₂ emissions from their eight FCCU units; including three SNCRs, one SCR, three additional WGS (total of five required)

4. use catalyst additives to reduce NO_x at all FCCUs not equipped with SCR
5. use catalyst additives to reduce SO₂ from the three FCCUs not equipped with WGS
6. install sufficient ultra-low NO_x burners to reduce NO_x from heaters and boilers over 40 million Btu/hr by 4,000 tons/year collectively
7. reduce the use of liquid and solid fuel so that SO₂ emissions are reduced by 1,300 tons/year.

The U.S. also has a number of New Source Performance Standards (NSPS) that apply to the petroleum refining sub-sector. These include NO_x emission limits for new boilers and heaters, and SO₂ emission limits for FCCUs and sulphur recovery units.

6 Costs for Emission Reductions

Costs for control technologies were based on data provided in several technical reports.^{xix,xx,xxi,xxii} Where applicable, costs were scaled based on production capacity. The percent emission reductions in Tables F-4 and F-5 are for all sub-sector emissions. The range of costs presented take into account the results obtained through the use of cost control models and input from individual facilities during consultation. For NO_x reductions, the use of LNBs, SNCR and SCR were applied to the major NO_x sources at the facilities: typically boilers with capacities over 100-250 million Btu/hr and the FCCU/CO boilers.

Table F-4: Emissions Reductions and Cost of NO_x Control Technologies for the Petroleum Refining Sub-sector

Technology	Reduction from 2000 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of NO _x removed)
	(%)	(kt)	(\$ Millions)			
LNB	13-23	1.5-2.6	85-130	1.9-2.9	9.2-14	\$2,000-5,500
SNCR	26-36	3.0-4.1	60-110	4.4-7.8	9.6-17	\$2,300-5,700
SCR	64-73	7.3-8.3	200-560	42-105	60-150	\$7,300-18,000

LNB – Low NO_x Burners; SNCR – Selective Non-Catalytic Reduction; SCR – Selective Catalytic Reduction

Table F-5: Emissions Reductions and Cost of SO₂ Control Technologies for the Petroleum Refining Sub-sector

Technology	Reduction from 2000 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of NO _x removed)
	(%)	(kt)	(\$ Millions)			
WGS on FCCU/CO Boilers	30-47	18-28	66-100	11-17	17-26	\$600-1500
DeSO _x Catalyst for FCCU/CO Boilers	4-5	2.4-3.2	0	4.8-14	4.8-14	\$1500-6000
TGTU for Sulphur Recovery Units	11-30	6.7-18	17-36	0.3-1.8	0.9-4.9	\$100-800

WGS – Wet Gas Scrubbing; FCCU/CO Boilers – Fluidized Catalytic Cracking Unit/Carbon Monoxide Boilers; TGTU – Tail Gas Treatment Unit

Appendix G: Pulp and Paper

1 Overview of the Pulp & Paper Sub-sector in Ontario

The Pulp and Paper Sub-sector is made up of 26 pulp mills operating at 17 manufacturing sites in Ontario. Several companies in Ontario employ more than one pulp making process (e.g., kraft, thermo-mechanical (TMP), groundwood, etc.) at their facility. The major pulp producing companies include Abitibi-Consolidated, Bowater, Domtar, Kimberly-Clark, Tembec, Marathon Pulp, and Weyerhaeuser. Chemical (e.g., kraft) pulp mills tend to be larger emitters of nitrogen oxides (NO_x) and sulphur dioxide (SO₂) than mills using other production processes. The nine Ontario kraft pulp mills are the focus of the study, since it is estimated that they account for over 60% of the NO_x emissions and over 80% of the SO₂ emissions from the pulp and paper sub-sector in Ontario. The reference production rates for Ontario's kraft pulp mills are listed in Table G-1.

Table G-1: Ontario's Kraft Pulp Mills' Reference Production Rates^{xxiii}

Facility	Bleached Kraft Pulp (tonne/day)
Abitibi-Consolidated Company of Canada, Fort Frances	611
Bowater Canadian Forest Products Inc., Thunder Bay	1,449
Domtar Inc., Cornwall	673
Domtar Inc., Espanola	1,216
Kimberly-Clark Canada Inc., Terrace Bay	1,372
Norampac Inc., Red Rock	NR
Marathon Pulp Inc., Marathon	533
Tembec Industries Inc., Smooth Rock Falls	415
Weyerhaeuser Company Limited, Dryden	940
Total	7,209

In the above table "NR" means not recorded.

2 *Production Process Description*

In the kraft pulping process, wood is digested under elevated temperature and pressure using a “cooking liquor” of sodium hydroxide and sodium sulphide. This separates the lignin and wood resins from the cellulose fibre pulp. The digester contents are separated into a pulp slurry and spent cooking liquor.

The pulp slurry is washed and chemically bleached to brighten the pulp before being used to make paper. The spent cooking liquor is concentrated in an evaporator system and then fired in recovery boiler(s). The inorganic cooking chemicals, recovered as a deposit from the boiler furnace floor, are used in preparing fresh cooking liquor.

In addition to steam produced in the recovery boiler, fossil fuels and wood waste are fired in boilers to generate additional process steam and electricity.

3 *Emissions*

The majority of the emissions of NO_x and SO₂ are generated by combustion equipment that is used to produce steam for the facility. There are large variations in the NO_x and SO₂ emission intensities of the facilities due to a number of factors:

- some facilities use steam to generate electricity
- one facility purchases steam from a third party
- in addition to kraft production some facilities have other production operations (e.g., thermo-mechanical (TMP) mill, stone-groundwood mill, de-inking facility, newsprint making facility, etc.) that have additional steam requirements
- facilities that use wood-fired boilers and natural gas-fired boilers have much lower SO₂ emissions than facilities burning heavy fuel oil . Some facilities do not have access to natural gas or waste wood.

3.1 *Emission Sources*

At kraft mills the major sources of NO_x and SO₂ emissions are:

- Power/utility boilers fired with biomass and/or fossil fuels;
- Recovery boilers; and
- Electricity generation.

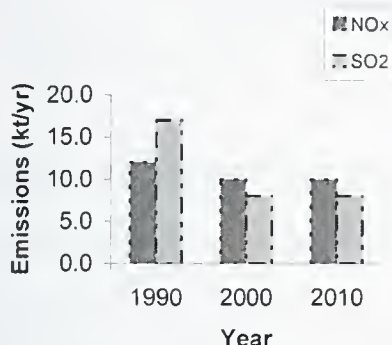
NO_x is generated in all fuel combustion equipment. Boilers fired with biomass (e.g., bark or wood chips) tend to have lower NO_x emissions than fossil fuel fired boilers. This is because

of the moisture content of these fuels, which tends to lower the flame temperature and thus reduce NO_x formation in the combustion process.

Biomass does not inherently have an appreciable amount of sulphur, resulting in negligible SO₂ emissions from biomass combustion. SO₂ emissions are generated by the combustion of sulphur-containing fuels (i.e., spent cooking liquor and fossil fuels).

3.2 Emission Trends

Figure 7: NO_x and SO₂ Emissions Trends - 1990, 2000 and Projected 2010 Emissions



3.2.1 NO_x Trends

The emissions of NO_x from the pulp and paper sub-sector represent approximately 2% of Ontario's emissions in 2000. Total emissions of NO_x from 1990 to 1999 decreased 16% from 12.2 to 10.2 kt. These reductions were mostly achieved through process energy efficiency improvements. The sub-sector has predicted no further decreases (2000-2010).

3.2.2 SO₂ Trends

The emissions of SO₂ from the pulp and paper sub-sector represent approximately 1% of Ontario's emissions in 2000. Total emissions of SO₂ from 1990 to 2000 decreased 51% from 16.6 to 8.2 kt. These reductions were mostly achieved through process energy efficiency improvements and some fuel switching. The sub-sector has predicted no further decreases (2000-2010).

3.3 Estimating Emissions

Emissions are estimated using a variety of techniques. No sources in the pulp and paper sub-sector are known to be equipped with continuous emission monitors. In the nine kraft pulp mills there are a total of 17 sources that have heat inputs greater than 250 million Btu/hr. Only two of the 17 sources use more than 50% fossil fuel.

4 Emission Reduction Technologies

There are several different technologies and practices that can be applied to control emissions of NO_x and SO₂ from pulp mills. Tables G-2 and G-3 summarize the combustion modification and post-combustion control technologies used to reduce NO_x and SO₂ from kraft pulp mills. Generally applicable technologies, such as low NO_x burners, are not shown here, but are used in the cost analysis that follows.

It should be noted that the combustion equipment in the pulp and paper sub-sector is typically unique in the types and ratios of fuels fired. As such, a number of emission control technologies may not be applicable for any given piece of equipment.

4.1.1 NO_x Control Options

Table G-2: NO_x Control Technologies and Approaches for the Pulp & Paper Sub-sector

Technology	Applicable To	Emission Reduction	Remarks
Process Modifications & Energy Efficiency Improvements	All sources	Varies	Using less fuel reduces the generation of NO _x . Each facility will have different opportunities for optimizing processes and equipment to reduce fuel consumption.

4.1.2 SO₂ Control Options

Table G-3: SO₂ Control Technologies for the Pulp & Paper Sub-sector

Technology	Applicable To	Emission Reduction	Remarks
Post-combustion controls			
Lime Injection Multistage Burner (LIMB)	Power and recovery boilers	55%	High capital and operating cost
Lime Spray Drying (LSD)	Power and recovery boilers	90%	High capital and operating cost
Wet scrubber (alkaline liquid absorption)	Recovery boilers	90%	Can be used on new or existing recovery boilers.

Technology	Applicable To	Emission Reduction	Remarks
Limestone Forced Oxidation (LSFO)	Power and recovery boilers	95%	High capital and operating cost
Alternative Approaches			
Fuel switching	Coal or oil-fired equipment	Varies	Cost varies depending on fuel availability and need for equipment modification
Increase the Dry Solids Content of Black Liquor	Recovery boilers	Varies	Increasing the dry solids content of the black liquor can reduce SO ₂ emissions. However, NO _x emissions can increase if solids are super-concentrated, if other remedial measures are not implemented.

5 *Emission Limits in other Jurisdictions*

In the U.S., at the federal level there are no limits for NO_x and SO₂ for the pulp and paper sub-sector beyond the new source performance standards (NSPS) for new or modified boilers and the application of the NO_x SIP Call to large fossil-fired boilers in affected areas. At the local level, NO_x and SO₂ at most facilities are regulated by the limits in their site specific operating permits. Most site specific operating permits do not include limits for NO_x and SO₂ but focus on particulate matter (PM) and total reduced sulphur (TRS).

6 *Costs for Emission Reductions*

A review of the emission data estimates for 1999 identified four kraft pulp mills that either emitted more than 1.5 kt NO_x or 1.0 kt SO₂ annually. Therefore costs for control options were developed only for these four facilities. The four mills represent approximately 50% of the NO_x emissions and 70% of the SO₂ emissions from the nine Ontario kraft mills for 2001. Cost estimates were not scaled to include any of the other kraft pulp mills since costs are very site-specific.

Low Excess Air (LEA) and Low NO_x Burners (LNB) are only applicable to some combustion sources in this sub-sector. The sub-sector has no experience with the use of SCR to reduce NO_x emissions. Similarly, with the exception of fuel switching, the sub-sector has no experience with the SO₂ control technologies listed in Table G-5. This contributes to the uncertainty of the estimated costs for these control technologies.

Fuel switching is a possible solution to reduce SO₂ emissions from some combustion equipment at two of the four kraft mills studied. Since pulp mills use a variety of fuels and the proportion of fuel usage by type changes each year with fluctuating fuel costs, the potential reduction of SO₂ emissions will also vary from year to year.

Fuel switching may not be an option for mills and equipment using non-fossil fuels (e.g., biomass) or low-sulphur fossil fuels. In addition, at some remote sites natural gas is not available as a substitute for fuel oil and/or coal.

Tables G-4 and G-5 provide a summary of emission reductions and costs for selected control technologies applicable to the four kraft pulp mills studied. The percent emission reductions in Tables G-4 and G-5 are for all sub-sector emissions.

Table G-4: Emissions Reductions and Costs of NO_x Control Technologies for Four Pulp and Paper Mills

Technology	Reduction from 1999 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of NO _x removed)
	(%)	(kt)	(\$ Millions)			
LEA	0	0.04	\$0.24	\$0.01	\$0.03	\$720
LNB	2	0.2	\$7.4	\$0.2	\$0.9	\$4,200
SCR	23	2.3	\$102	\$20	\$29	\$12,400

LEA – Low Excess Air; LNB – Low NO_x Burners; SCR – Selective Catalytic Reduction

Table G-5: Emissions Reductions and Costs of SO₂ Control Technologies for Four Pulp and Paper Mills

Technology	Reduction from 2000 Emissions		Capital Cost	Annual Operating Costs	Annualized Costs (\$/year)	Cost Effectiveness (\$/tonne of SO ₂ removed)
	(%)	(kt)	(\$ Millions)			
FS	7-22%	0.6 – 1.8	0	2.8-7.3	2.8-7.3	\$3,000-5,300
LIMB	26%	2.1	83	10	17	\$8,212
LSD	44%	3.6	314	15	42	\$11,660
LSFO	42%	3.5	284	18	42	\$12,240

LSD – Lime Spray Drying; LSFO – Limestone Forced Oxidation;
LIMB – Lime Injection Multistage Burners; FS – Fuel Switching

Abbreviations and Acronyms

BACT – Best Available Control Technology

BOF – Basic Oxygen Furnace

BREF – Best Available Techniques Reference Document produced by the EIPPCB

Btu – British Thermal Unit

CaSO₃ – Calcium sulphite

CaSO₄ – Calcium sulphate

CCME – Canadian Council of the Ministers of the Environment

CEM – Continuous Emission Monitor

CEPA – Canadian Environmental Protection Act

CO – Carbon monoxide

CO₂ – Carbon dioxide

COG – Coke Oven Gas

DRI – Direct Reduced Iron

EAF – Electric Arc Furnace

EC – Energy Conservation

EE - Energy Efficiency

EIPPCB – European Integrated Pollution Prevention Control Bureau

ENGO's – Environmental Non-Government Organizations

ERT – Emission Reduction Trading

EU – European Union

FCCU – Fluidized Catalytic Cracking Units

FGD – Flue Gas Desulphurization

FGR – Flue Gas Recirculation

FIP – Federal Implementation Plan (U.S.)

FS – Fuel Switching

ft³ – cubic foot

H₂S – Hydrogen Sulphide

hr – hour

ICBA – International Carbon Black Association

ISO – International Organization for Standardization

ISO 14000 – ISO Environmental Management System Standard

kt – kilotonnes (thousand tonnes)

LEA – Low Excess Air

LIMB – Lime Injection Multistage Burner

LNB – Low NO_x Burners

LSD – Lime Spray Drying

LSFO – Limestone Forced Oxidation

MOE – Ontario Ministry of the Environment

NO_x – Nitrogen oxides (the sum of nitrogen dioxide (NO₂) and nitric oxide (NO)). In this report the figures for NO_x are expressed as NO₂ equivalent.

NSPS – New Source Performance Standard

OFA – Over-fire Air

O.Reg. – Ontario Regulation

O&M – Operating and Maintenance

PM – Particulate Matter

PSD – Prevention of Significant Deterioration

PSL – Priority Substances List

RACT – Reasonably Available Control Technology

SCA – Staged Combustion Air

SCR – Selective Catalytic Reduction

SIP – State Implementation Plan

SNCR – Selective Non-Catalytic Reduction

SO₂ – Sulphur dioxide

SOP – Environment Canada's Strategic Options Process

TBRC – Top Blown Rotary Converter

TGTU – Tail Gas Treatment Unit

TMP – Thermo-mechanical Pulp

TRS – Total Reduced Sulphur

U.S. – United States

U.S. EPA – United States Environmental Protection Agency

ULNB – Ultra-low NO_x Burners

VOC – Volatile Organic Compounds

WGS – Wet Gas Scrubbing

Glossary

"catalyst" means a substance that enables or accelerates a chemical reaction without itself undergoing a change.

"chemical sweetening" means the process of removing sulphur compounds from petroleum feedstock to improve colour, odour, and oxidation stability.

"clinker" means the material exiting a cement kiln which, when mixed and processed with gypsum, limestone and supplementary cementitious materials, produces blended cement.

"coking" means heating a heavy feedstock from the vacuum distillation unit in insulated drums. Liquids and vapours are distilled into additional products that can be further processed within the refinery. Petroleum coke, a coal-like substance, is left as residue in the coke drum. Petroleum coke is removed from the coking drum and may be used as a fuel.

"code of practice" means a document that describes the operational activities and associated environmental concerns of a sub-sector and recommends practices and performance standards to mitigate these concerns.

"control order" means a document that requires the emitter to take specific action, typically to reduce emissions, with an associated deadline. It is authorized by statute, binding upon the recipient, and directly enforceable by prosecution.

"co-generation" means the production of both steam and electricity in the same equipment. Typically the steam would be used at the facility where the co-generation equipment is located and the electricity could be used internally, sold to the electricity distribution grid or a combination of both.

"cracking" means the decomposition of a larger hydrocarbon molecule into smaller molecules

"decant oil" means a residue from fluidized catalytic cracking units in the petroleum industry.

"firebrick" means a special material, also known as "refractory", that protects the steel shell of a kiln from the intense heat produced inside the kiln.

"fly ash" means the powdery residue left after the combustion of powdered coal.

"hydrotreating" means using hydrogen to chemically combine with sulphur compounds, which are then extracted for further processing as hydrogen sulphide.

"iron ore fines" means iron ore particulate material that is too small to feed into a blast furnace. Iron ore fines are collected from material storage and handling operations at integrated iron and steel mills.

"kiln" means a rotary cement kiln. A kiln is a large, slightly inclined steel cylinder lined with firebrick that slowly rotates. The raw material feed is continuously loaded at the higher end of the kiln and is heated as it progresses to the lower end where it is continuously unloaded. Fuel is combusted at the lower end of the kiln to generate the heat required to produce cement clinker.

"light ends" means crude oil molecules with the fewest number of atoms. They are referred to as light ends because they have the lowest density. Naphtha and butane are examples of light ends.

"mass balance" means the method of showing the origin and ultimate disposition of all the materials flowing through a process. One definition of the mass balance method is an accounting system for material flows and changes in inventory of material for a system.

"matte" means the impure product of smelting non-ferrous metal (sulphide) ores.

"metallurgy" means the science of the properties of metals.

"metallurgy adjustments" means modifying a metal's chemical mixture to achieve the desired properties of the final metal product.

"oxidizing environment" means an area where oxygen is available to be combined with material in a system.

"oxygen facility" means a plant producing oxygen to be used at a facility.

"pig iron" means crude, unprocessed iron.

"pyrite" means a mineral, such as iron sulphide, that contains sulphide.

"pyrolysis" means chemical decomposition by action of heat. Also referred to as "thermal cracking".

"reducing environment" means an area where oxygen is not available to be combined with material in a system.

"scrubber" means an add-on air pollution control device which uses a liquid to capture ("scrub") gaseous and/or particulate contaminants from an exhaust stream.

"secondary plume" means a residual visible air emission resulting from the condensation and reaction of chemicals in the gas stream after leaving the stack. Sometimes referred to as a "detached plume".

"sector" refers to the aggregate of individual sub-sectors (see definition of "sub-sector" below). Examples are industry, electricity and transportation sectors.

"sinter" means the agglomerated, fused material that is produced from a sinter facility. In the integrated iron and steel sub-sector, sintering involves the heating of iron ore fines and waste iron oxides to produce a semi-molten mass that solidifies into porous pieces of sinter with the size and strength characteristics necessary for recycling the material by feeding it into a blast furnace.

"slag" means the dross (a scum of "waste material") separated from metallic ores during smelting or from molten metal during refining. Steelmaking slag can be used as supplementary cementitious material in cement production.

"slurry" means a suspension of fine solid material in liquid.

"smelting" means the process of extracting metal from ore by melting.

"source" means any mobile, area, or stationary source emitting NO_x or SO₂ into the atmosphere.

"stack testing" means one or a series of short-term measurement(s) used to determine the amount of contaminant being emitted from an exhaust.

"sub-sector" refers to an individual group of industries with similar design and processes, often producing similar products. The sub-sectors referred to in this report are carbon black, cement, glass, iron and steel, non-ferrous smelting, petroleum refining and pulp and paper.

"supplementary cementitious material" means material such as steel making slag, fly ash and other minerals (other than gypsum and limestone) that can be added to cement to increase the quantity of blended cement produced while maintaining product quality.

"visbreaking" means a non-catalytic process that converts atmospheric and vacuum distillation residues via pyrolysis into gas, naphtha, distillates and visbroken residue. Atmospheric and vacuum distillation residues are typically charged to a visbreaker to reduce fuel oil viscosity and increase distillate yield in the petroleum refinery.

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